Idaho Public Utilities Commission

Case No. GNR-E-11-03, Order No. 32697
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PUC order addresses several small-power production issues

State regulators today established the ground rules going forward for renewable power projects that enter into sales agreements with regulated utilities.

The rapid development of wind projects led the utilities to petition the Idaho Public Utilities Commission in November 2010 to investigate the methods the commission uses to set the price that should be paid renewable developers. Utilities complained that the federal Public Utility Regulatory Policies Act, or PURPA, was forcing them to buy power they did not need at rates that were too high.

Congress passed PURPA in 1978 to encourage renewable power development. It requires regulated utilities to buy energy from qualifying renewable small-power projects, called Qualifying Facilities (QFs). Although the "must-buy" provision of PURPA is a federal law, Congress left it to states to determine the rate to be paid QF developers. That rate, called an avoided-cost rate, is to be based on the cost the purchasing utility avoids by not having to generate the power itself or buy it from other sources. Because ratepayers end up paying for QF energy, the intent of PURPA is that, cost-wise, ratepayers are indifferent as to whether their utility uses more traditional sources of power or buys from qualifying renewable projects.

Here are the major components of today's order. Details are included later:

- The cap for wind and solar projects seeking the commission's published avoided-cost rates is 100 kW. The eligibility cap for all other QFs remains 10 average megawatts. Wind and solar projects larger than 100 kW are eligible for a negotiated avoided-cost rate using each utility's long-range growth plan, called an Integrated Resource Plan, as the basis for the negotiation. The commission denied an Idaho Power Company proposal to use the IRP-based negotiated rate methodology for all QFs.
- The commission denied a proposal by Idaho Power Company that would relieve it from its PURPA mandatory purchase obligations by allowing it to curtail generation from some projects during certain periods of light customer load. The commission said that while federal law allows curtailment under specified conditions, Idaho Power did not provide sufficient evidence to support its proposal.

- Projects with published-rate contracts will be able to keep the Renewable Energy Certificates (RECs or "green tags") associated with their projects. Wind and solar projects larger than 100 kW and all projects larger than 10 average megawatts with negotiated contracts using the IRP methodology will retain one half of the RECs associated with their project while the purchasing utility retains the other half.
- Fuel price forecasts and load forecasts will be updated on June 1 of each year so that the price paid QFs more accurately reflects avoided cost. Up until now, a large part of the rate paid QFs was updated only when the Northwest Power Planning and Conservation Council issued an updated natural gas price forecast. The new annual update will be based on natural gas price forecasts provided by the federal Energy Information Administration's Annual Energy Outlook.
- The maximum contract length for sales agreements between utilities and QFs remains 20 years. Utilities argued for five years. Alternatives to a 20-year contract may be negotiated by the parties and considered by the commission.
- New QF contracts will be paid for capacity based only on the project's ability to deliver during peak hours and when a utility's long-range plan shows the utility is capacity deficient Currently, QFs are paid for both energy and capacity, the latter being potential surplus the utility may need during peak-load hours.

"This commission has a long history of encouraging PURPA development," the commission said. "With the changes adopted herein, we believe that PURPA development can continue to thrive in a way that holds ratepayers harmless. QF projects that provide a utility with needed energy and capacity will be compensated accordingly. QF projects that are inconsistent and detrimental to a utility's load and resource balance will also be compensated at a rate that reflects the costs that the QF allows the utility to avoid by purchasing its generation."

Case background

In November 2010, Idaho Power Company, Avista Utilities and PacifiCorp (Rocky Mountain Power in eastern Idaho) filed a joint petition asking the commission to investigate issues related to small-power projects that qualify for published rates. The utilities contended a rapidly expanding number of wind projects were having a profound price impact on customers and on their transmission systems. The utilities claimed that the small-power projects PURPA was originally intended to encourage were instead being developed by sophisticated large-scale wind farms. The wind farms were broken down into smaller projects and located a mile apart so they could fall under the 10 aMW limit that qualified them for the commission's typically more attractive published rate. Combined, these projects could total up to 100 or 150 MW of power interconnecting at a single delivery point.

The commission partially granted the utilities' request to temporarily lower the eligibility cap for wind and solar projects to 100 kilowatts while it investigated the matter. Renewable power developers claimed the issues raised by the utilities could be resolved, not by lowering the eligibility cap, but by revising and updating the methods the commission uses to calculate the published rates so that they more accurately reflect avoided cost.

In June 2011, the commission affirmed its decision to maintain the 100 kW eligibility cap for published rates for wind and solar projects, due to the intermittency of generation from those projects and the potential for disaggregation. Utilities were still subject to the "must-buy" provisions to purchase QF power from wind and solar projects, but at a rate negotiated between the utility and the QF using a commission-approved Integrated Resource Plan (IRP) methodology. This method recognizes the individual generation characteristics of each project by assessing when the QF is capable of delivering its resources against when the utility is most in need of the energy.

At that time, the commission also stated its intent to initiate an additional proceeding to investigate both the published rate methodology and the IRP methodology to determine the rates that should be paid QFs. Today's order is a result of that proceeding.

<u>Eligibility cap</u>

The order re-affirms the eligibility cap at 10 aMW for all QFs other than solar and wind, which will remain at 100 kW.

"Wind and solar are intermittent resources with unique characteristics," the commission said. "A 100 megawatt wind farm or solar project can be broken up into 10 aMW pieces in order to maintain multiple published rate contracts." That, the commission said, no longer produces a rate that accurately reflects the value of the energy to the utility.

"Congress intended to allow PURPA cogeneration and small renewable projects to produce and sell power without the burden of being regulated as an electric utility," the commission said. "Congress did not intend for multi-national corporations to fund large wind farms for the benefit of their shareholders and the detriment of utility ratepayers. Indeed, PURPA transactions are intended to hold ratepayers harmless."

<u>Curtailment</u>

Idaho Power proposed a new tariff to establish a process that relieves utilities from mandatory purchase obligations during certain periods of light customer load.

Idaho Power claimed that federal regulations allow such curtailment to avoid cost increases to customers when the utility must back-down baseload units to accommodate QF output. Consequently the utility and its customers "then suffer an otherwise unnecessary increase in cost when it must use higher-cost power sources during the interval required to ramp baseload units back up when higher load conditions resume," Idaho Power claimed.

Renewable developers argued that PURPA allows for curtailment only to meet emergency operational needs, that current avoided-cost rates are already adjusted for curtailment, and that curtailment amounts to a retroactive modification of existing contracts.

The commission acknowledged that Idaho Power "has had to accept what it considers a glut of QF power."

"The commission, through these proceedings, is attempting to provide Idaho Power and the other commission-regulated utilities with the tools necessary to manage QF power without harming ratepayers. However, we find that Idaho Power has not provided sufficient information or persuaded us about its must-run resources, the frequency of such conditions and the transparency" of its proposed tariff, the commission said. "If the company believes that over-supply of QF power presents operational problems during light-load periods then it should this address issue when it negotiates new power purchase agreements."

Renewable Energy Certificates

RECs, sometimes called green tags, represent proof that one megawatt of electricity was generated from a renewable energy source that meets federal guidelines. The certificates can be sold on the open market and are typically purchased by utilities to satisfy requirements that they purchase a percentage of their energy from renewable resources. Idaho does not have a renewable portfolio standard and there is no federal standard.

Because RECs are "unbundled" from the energy itself and sold separately, there is a dispute as to who owns the RECs: the QF developer or the utility.

The utilities claim RECs should belong to the utility because PURPA requires they purchase the QF power and without that must-buy provision the QF power likely would not be purchased. Avista Utilities noted that eight states have determined that REC ownership should be vested in the utility.

Renewable power developers argue that assigning RECs to utilities violates PURPA by discouraging future QF development and providing a windfall for utilities. If RECs are assigned to utilities, then they should be compensated for what amounts to a "taking," of QF property, they argued. Some intervenors in the case argued that the commission does not have the authority to resolve REC ownership, particularly since the Idaho Legislature has declined to address REC ownership.

The commission acknowledged that while it exercises limited jurisdiction based upon authority given it by the Legislature, it is well settled law that the commission is granted authority to review QF contracts and resolve disputes between QFs and utilities. The disposition of RECs is now a term that is found in most, if not all, PURPA contracts. In fact, the commission has already determined that REC ownership should be split 50-50 in at least five PURPA contracts.

Further, the commissions said it has authority to determine ownership because RECs directly affect customer rates. The full cost of buying QF power is directly recovered from Idaho Power and Avista customers through the annual Power Cost Adjustment (PCA) mechanism and from Rocky Mountain Power customers through the Energy Cost Adjustment Mechanism. When utilities file a general rate case, those costs become part of base rates.

Because both the utility and the QF are contractually and inextricably joined in the production, sale and purchase of renewable power, the commission split REC assets equally between the two parties to negotiated sales contracts based on the IRP methodology. For published rate contracts, the developer is allowed to retain all the RECs because rates for those contracts are based on the cost to provide power using a combined cycle natural gas plant as the surrogate resource. If the utility were not avoiding costs by accepting the QF energy, it would build a gas resource. Gas resources do not produce RECs. Thus, QF projects are entitled to all the RECs under these types of contracts, the commission said.

Splitting the RECs 50-50 for wind and solar projects larger than 100 kW and for all projects larger than 10aMW "mitigates those arguments that assigning RECs to either the QF or the utility in their entirety represents a revenue windfall to the recipient," the commission said. Under the IRP methodology, "both the QF and the utility (including its ratepayers) share the benefits of selling RECs."

Capacity payments

The commission determined that capacity payments should be made only to projects that provide generation during peak hours when the utility is most in need. Currently, all QF projects receive a merged energy and capacity payment. The separation of the two payments will apply only to new projects and not to existing projects that are renewing or extending their contracts.

Some intervenors argued that projects should be eligible for capacity payments throughout the term of their contracts with no consideration of when a utility becomes capacity deficient. Denial of capacity payments during a period of claimed surplus does not put a QF facility and a utility-owned generation plant on an equal footing, they claimed.

The commission disagreed, stating that consideration of a utility's need and potential surplus energy does treat a QF like a utility-owned resource. "A utility cannot be compensated by its customers for energy produced from a generating facility until the utility establishes a need for such new generation," the commission said.

Developers expressed concern that a utility could manipulate variables within the IRP planning process that would negatively impact the pricing of capacity paid to a QF. To address those concerns, the commission ruled that when a utility submits its biennial IRP to the commission, a separate case will be opened to determine the capacity deficiency component of the IRP.

Security deposit, delay damages

The commission adopted a proposed settlement by 13 of the 25 parties to the case that requires QFs to post a security deposit, or performance bond, within 30 days after the commission issues its final order approving a power purchase agreement. The deposit is set at $45 per kilowatt of a QF's nameplate capacity.

In the event the project fails to meet its operation date, delay damages would be calculated based on the difference between the regional market rates for electricity and the rates in the power purchase agreement. Requiring new projects to pay the difference between market and contracted rates ensures the utility and its customers won't be paying extra if the utility has to buy power on the market or generate itself to make up for the lost power due to the project's failure to meet its online date. Projects have 120 days to cure their default before the agreement may be terminated.

The proposed security and damages provisions are applicable only to new power purchase agreements.

The complete order is available on the commission's Web site, www.puc.idaho.gov. Click on "File Room," in the upper left-hand corner, then on "Recent Orders and Notices," for Case No. GNR-E-11-03.

The commission's order is final. Parties may petition for reconsideration by no later than January 8.

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